UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southwest Power Pool, Inc.	Docket Nos.	ER04-48-000 RT04-01-000 ER04-434-000 ER99-4392-000
Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design	Docket No.	RMO1-12-000

Comments of

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on behalf of
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It is a pleasure to have the opportunity to participate in this workshop concerning the future development of the Southwest Power Pool (SPP) as a Regional Transmission Organization (RTO). As noted in the published agenda, I am participating in this Workshop as a representative of Golden Spread Electric Cooperative, Inc. (Golden Spread), a generation and transmission cooperative headquartered in Amarillo, Texas. Golden Spread is owned by sixteen member distribution cooperatives which serve retail customers located in the SPP and/or the Electric Reliability Council of Texas (ERCOT). The Golden Spread member load served in the SPP is located predominantly in the control area of Southwestern Public Service Company (SPS), which is in the western-most portion of the SPP, and borders ERCOT to the South and the WECC to the West.

Golden Spread currently serves the full requirements power supply for 11 of its members in the SPP. It supplies these requirements with a combination of purchases from SPS and with power supplied by Mustang Station, a 488 megawatt combined cycle gas-fired power plant located near Denver City, Texas.

According to the Notice published by the FERC, the purpose of this Workshop is to discuss "reasonable timetables for RTO development activities to benefit customers within the region." I would like, at the outset, to emphasize the stated objective of benefitting "the customers." Golden Spread agrees wholeheartedly with this stated objective. We are concerned, however, that absent candid recognition of existing transmission limitations and pragmatic responses to deal with those limitations, the SPP may implement markets that ultimately will be detrimental to those customers that the SPP RTO is supposed to benefit.

Based on recent experience (recognizing that virtually all experience in the effort to restructure the power markets is relatively "recent"), our concerns are justified. There have been notable failures in the recent past, and they are not fully resolved today. The final chapters in the California market fiascos of 2000 and 2001, for example, remain to be written. Key FERC orders remain to be issued and appeals of those orders no doubt will follow. California is not the only example where a power market - developed with the stated purpose of benefitting consumers later - revealed flaws that resulted in fundamentally unjust and unreasonable rates. This past Tuesday, the United States Court of Appeals for the District of Columbia Circuit issued a decision that reversed and remanded a FERC order which had upheld a decision by the New York ISO to act, after-the-fact, to reduce spot market prices established during May 8 and 9, 2000 from $3,487 per megawatt hour to approximately $300 per megawatt hour.[1]

Let's put this number in perspective. A 250MW combined cycle generating unit with a 7,200 heat rate has a fuel cost of $43.20 when gas costs $6 mmBtu. Over five hours at full load, the total fuel cost would be $54,000. If such a plant is lost due to a forced outage, and replacement power cost $3,487, the five hour cost will be **$4,358,750**! Furthermore, every other purchaser in the market would see similar costs.

Lessons have been learned, and hopefully the market "planners" will attempt to adopt protective measures that guard against such excessive charges. But it seems that a first order of business in such planning is a thorough and candid analysis of the system capabilities and limitations as they exist today, because those factors will determine not just the size and scope of

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[1] PSEG Energy Resources & Trade LLC v. FERC, , No. 02-1276, slip op. (D.C. Cir March 16, 2004).

the market, but whether a competitive market can exist within the system as currently configured. With this general caveat in mind, let's turn to the SPP.

The stated objective of the SPP is to establish a "competitive" power market. I posit that a "competitive" market is one where multiple buyers can access multiple sellers, and price discipline is imposed by the competing sellers' desire to increase market share or at least not lose market share. I do not consider a market competitive where buyers essentially have access to only a single seller, and must purchase power at rates dictated by that seller. If a competitive market contemplates access to multiple suppliers, it is necessary to understand what are the physical capabilities of the transmission system in the SPP as that system exists today. If the system is physically or contractually constrained, and if real (as opposed to theoretical) transmission access is a condition precedent to a competitive market, it follows that you cannot have a competitive market until the transmission problems are resolved. If such limitations do exist, and SPP moves forward to implement a "market" nevertheless, it is essentially ratifying the exercise of market power by those sellers who by virtue of control of transmission and/or generation, can command prices without the tempering effect of competition.

What is the situation in the SPP? First, from what I have been able to learn the situation is really grim. I understand that as a practical matter there is virtually no unsubscribed transmission capacity in many parts of the SPP. If that is correct, competitive markets cannot exist in those areas. It may be possible at some future time to make those markets competitive through transmission improvements, but if in fact there is no access on Market Day 1, I sincerely hope that the regulators in the room would join with the customers in concluding that the public interest is not served by allowing prices to rise to whatever level such a so-called "market" would demand. I also hope that the SPP agrees that it would be fundamentally imprudent to implement a new market without first even attempting to identify such areas, and adopting appropriate pricing limitations from the outset. In this regard, it would seem appropriate for the SPP to analyze the historic commitment and dispatch practices of utilities operating control areas in its footprint to identify areas where there are obvious load pockets, as evidenced by internal transmission limitations necessitating operation of locally situated, high cost generation.

Furthermore, it is my understanding that existing transmission planning and load flow modeling practices may actually have the consequence of undermining the development of competitive markets. For example, the SPP calculates the effect of new generator interconnections and changes in designation of network resources by running load flow models which compare a Base Case to a Change Case. The SPP Base Case incorporates control area load and control area resources, as reported to the SPP by participating control areas. For future years, projected loads and resources are incorporated in each future year Base Case. However, the data supplied to the SPP by participating control areas does not reflect only the existing resources and known resource additions. If the existing resources and known control area resources additions are inadequate to serve projected control area load, the control area utility will "assume" the existence of additional resources as necessary to "balance" the load flow. In some cases it is assumed that additional generation will be installed, while in other cases the control area utility may assume additional imports from outside the control area. These planning "assumptions" are made even though there are no plants committed for construction and no off-system supplies committed for purchase.

For example, the SPP Base Case for future years shows the existence of new generation, Tolk Units 3 and 4, at the SPS Tolk generating station near Muleshoe, Texas. Those units have not been announced, have not been permitted, and probably could not be built by SPS given prevailing Texas regulatory policies. Nevertheless, they populate the SPP Base Case, and any future transmission request is measured against the hypothetical circumstance that these units in fact exist and are operating. When the Base Case/Change Case comparison is made, the model may identify system deficiencies (which in fact may not exist due to the unfounded assumptions in the Base Case) and cost of correcting those calculated deficiencies may be a condition precedent to approval of the new network resource.

The problems associated with the current scheme of Base Case/Change Case modeling goes beyond errors injected by fictitious Base Case assumptions. Assume that a network customer has requested designation of a new network resource and the Base Case is entirely accurate. In other words, there exists a balance of existing loads and projected resources. The network customer has load in load Area A that has been supplied for many years at cost-based rates by a supplier in Area C, some 300 miles distant. The supplier in Area C serves notice of termination of the cost-based supply contract, and the network customer proposes to respond by designating as a new network resource a new generation unit that will be constructed in Area A, adjacent to its load. The SPP Base Case/Change Case analysis shows that this change in designation of network resource will cause an overload in Area B, some 200 miles distant from the network load and the proposed network resource. Why? Because in the Base Case, the transmission system in Area B depended on the displacement effect of the network customer's purchase from the supplier in Area C. Absent that power displacement, the transmission system in Area B was inadequate to meet existing obligations - even obligations associated with what may have been improvidently granted future point-to-point transmission reservations.

Having identified this transmission "problem," the question next turns to allocation of cost responsibility. Under the SPP rules, the network customer in Area A may be assessed cost responsibility for upgrading the system of the transmission owner in Area B. In effect, the SPP analytical process has "vested" the transmission owner in Area B with an entitlement to continued reliance on the benefit of displacement caused by the network customer's purchases from the supplier in Area C.

From a competitive standpoint, this practice has the effect of enhancing the market power of the supplier in Area C. If the network customer cannot obtain designation of its proposed generation as a network resource, it may be forced to renew with supplier C, but at much higher rates.

As the SPP moves forward with market development, the issue of "modeling" also may play a role in the allocation of FTRs. This may be particularly problematic for network customers who historically have relied on purchases from others, as opposed to ownership or control of generation. How do you source FTRs to a customer which historically has purchased system energy from one supplier, but is now facing termination of that supply?

These and other issues, as well as the general complexity of interconnected operations, make a strong case against broad implementation of a participant funding program for transmission upgrades. When it comes to designation of network resources for network loads or generation interconnections to serve network loads, it is difficult to see how you can identify with any precision either cause or benefit. A customer which changes a source of supply that necessitates addition of a network upgrade frees up other network capacity which may allow deferral of other network upgrades.

Furthermore, participant funding does not necessarily "protect" the native load. First, most transmission owners charge fixed transmission rates. That is, the rates do not decrease to reflect either reductions in rate base due to increases in depreciation and deferred tax reserves or the revenue effect of additional billing units attributable to load growth. A model that relies heavily on participant funding may serve only to create an earnings windfall for transmission owners. Second, requiring participant funding for generation additions could actually increase the overall cost paid by transmission users by a greater amount than if the transmission upgrade costs were rolled into transmission rates. If such costs are rolled in, the transmission customers pay them once as a transmission charge. However, it the transmission upgrade costs become an incremental cost of generation, new generation additions may be deferred until the market clearing price rises high enough to support both the cost of the new generation and the cost of the specifically assigned transmission upgrades. When this occurs, the overall additional expense borne by customers in the market will be many times the cost attributable to the incremental transmission facilities.

The challenges faced by the SPP as it seeks to develop competitive markets are great. There are market participants who today hold a commanding, if not absolutely controlling position in the market. They are long time operators of control areas and generation networks, and have great technical knowledge and capabilities. No doubt their interests will lie in preserving the control that they now have and expanding their opportunities elsewhere. All in all, entirely expected behavior. There are other market participants, however, with little or no control in the market, and which lack comparable technical knowledge and resources. They are at great risk if a market that is not competitive comes into being. Golden Spread understands and shares the desire of the SPP to move expeditiously with development of its RTO. But we caution against undue haste. There are areas where significant work remains to be done and it is essential that the work be done correctly if markets are to be competitive.